(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
28 August 2003 (28.08.2003)

PCT

(10) International Publication Number
WO 03/071090 A1

(51) International Patent Classification[7]: E21B 21/00, 21/08

(21) International Application Number: PCT/GB03/00775

(22) International Filing Date: 21 February 2003 (21.02.2003)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
10/082,459 25 February 2002 (25.02.2002) US

(71) Applicant (*for all designated States except US*): **HALLIBURTON ENERGY SERVICE, INC.** [US/US]; P O Box 1431, Duncan, OK 73533 (US).

(71) Applicant (*for MW only*): **WAIN, Christopher, Paul** [GB/GB]; A.A. Thornton & Co., 235 High Holborn, London WC1V 7LE (GB).

(72) Inventors; and
(75) Inventors/Applicants (*for US only*): **SWEATMAN, Ronald, E.** [US/US]; 163 Lakeside Drive, Montgomery, TX 77356 (US). **VARGO, Richard, F., Jr** [US/US]; 2142 Brinton Oaks Court, Katy, TX 77450 (US). **KULAKOFSKY, David, S.** [US/US]; 5715 Ashley Spring Court, Katy, TX 77494 (US). **ESCORCIA, Alvaro** [US/US]; 4114 Ivy Mist Court, Sugarland, TX 77479 (US). **RAVI, Krishna, M.** [US/US]; P.P. Box 5622, Kingwood, TX 77345 (US).

(74) Agents: **WAIN, Christopher Paul** et al.; AA Thornton & Co., 235 High Holborn, London WC1V 7LE (GB).

(81) Designated States (*national*): AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EC, EE, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NO, NZ, OM, PH, PL, PT, RO, RU, SD, SE, SG, SK, SL, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VN, YU, ZA, ZM, ZW.

(84) Designated States (*regional*): ARIPO patent (GH, GM, KE, LS, MW, MZ, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HU, IE, IT, LU, MC, NL, PT, SE, SI, SK, TR), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:
— *with international search report*
— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments*

For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

WO 03/071090 A1

(54) **Title:** METHODS OF DISCOVERING AND CORRECTING SUBTERRANEAN FORMATION INTEGRITY PROBLEMS DURING DRILLING

(57) **Abstract:** In accordance with a method of this invention, formation integrity problems are discovered, diagnosed and corrected in successively drilled subterranean well bore intervals. If one or more of well bore fluid outflows, formation fluid inflows or inadequate well bore pressure containment integrity are discovered in a drilled well bore interval, well logs are run and other relevant well bore data is collected in the drilled well bore interval and analyzed to provide a specific treatment using a specific pumpable sealing composition for sealing and increasing the pressure containment integrity of the well bore. Thereafter, the sealing composition is pumped into the drilled well bore interval whereby the well bore interval is sealed or the pressure containment integrity is increased, or both.

METHODS OF DISCOVERING AND CORRECTING SUBTERRANEAN FORMATION INTEGRITY PROBLEMS DURING DRILLING

BACKGROUND OF THE INVENTION

1. FIELD OF THE INVENTION

The present invention relates to methods of discovering, diagnosing and correcting formation integrity problems in successively drilled subterranean well bore intervals.

2. DESCRIPTION OF THE PRIOR ART

In the drilling of wells (for example, oil and gas wells) using the rotary drilling method, drilling fluid is circulated through a drill string and drill bit and then back to the surface by way of the well bore being drilled. The drilling fluid maintains hydrostatic pressure on the subterranean formations through which the well bore is drilled to thereby prevent pressurized formation fluids from entering the well bore and circulates cuttings out of the well bore.

Once the well bore has been drilled to the desired depth, a string of pipe referred to as casing is positioned in the well bore. A hydraulic cement composition is pumped into the annular space between the walls of the well bore and the casing and allowed to set thereby forming an annular sheath of hardened substantially impermeable cement in the annulus. The cement sheath physically supports and positions the casing in the well bore and bonds the casing to the walls of the well bore whereby undesirable migration of fluids between zones or formations penetrated by the well bore is prevented.

The subterranean formations into or through which well bores are drilled often contain naturally occurring or drilling induced weak zones having low tensile strengths and/or openings such as fractures, faults and high permeability streaks through which drilling fluid is lost from the well bores or pressurized formation fluids enter the well bores. The weak zones in the well bore have low pressure containment integrity and are subject to failure as a result of the hydrostatic pressure exerted thereon by drilling fluid or other treating fluid such as hydraulic cement slurries. That is, when a well fluid such as drilling fluid or a hydraulic cement slurry is introduced into the well bore, the combination of hydrostatic and friction pressure exerted on the walls of the well bore can exceed the strength of weak zones

in the well bore and cause well bore fluid outflows into the formation containing the well bore. When the formation contains induced or natural formation fractures, faults, or the like, well bore fluid outflows and/or pressurized formation fluid inflows, or both, can take place. The inflows and/or outflows make the well unstable. When a well becomes unstable, major problems such as lost circulation and blow-outs can occur which require the drilling operation to be terminated and costly remedial steps to be taken.

By way of further example, formation sands and shales can be encountered while drilling having unexpected low pressure containment integrity. Thus, at any depth during the drilling or completion of a well bore, the well bore fluid circulating densities and pressures can exceed planned or designed densities and pressures. The excess pressure exerted within the well bore can and often does exceed the subterranean formation pressure containment integrity which causes loss of well bore fluids into the formation. Such loss can lower fluid column heights in the well bore, reduce hydrostatic pressure below formation pore pressures and cause pressurized formation fluid inflow. When this happens, rig operators are often forced to prematurely set casing or run a drilling liner in the well bore making the overall cost of the well much higher than expected.

Thus, there are needs for reliable and quick methods of discovering, diagnosing and correcting formation integrity problems in well bores during drilling.

SUMMARY OF THE INVENTION

The present invention provides methods of discovering, diagnosing and correcting formation integrity problems during the drilling of successive subterranean well bore intervals. A method of the invention is comprised of the following steps. A first test is run in the well bore interval to determine if well bore fluid is being lost or if pressurized formation fluid is flowing into the well bore interval. A test is also conducted to determine the pressure containment integrity of the well bore interval. If it is determined that well bore fluid is being lost or pressurized formation fluid is flowing into the well bore interval or if it is determined that the pressure containment integrity is inadequate, or both, a pumpable sealing composition is provided for sealing the drilled well bore interval to prevent well bore fluid loss therefrom, to prevent pressurized formation fluid inflow thereinto and/or to increase the pressure containment integrity of the drilled well bore interval. The sealing composition is pumped into the drilled well bore interval to cause the drilled well bore interval to be sealed

or the pressure containment integrity of the drilled well bore interval to be increased, or both. Thereafter, the next successive well bore interval is drilled, the tests are repeated and the remedial steps are repeated if necessary. The process of drilling a well bore interval, determining the integrity of the well bore interval and conducting remedial steps when necessary is repeated until the well bore has reached total depth. Thereafter the well bore is completed in the normal manner without encountering additional well bore integrity problems.

When it is determined that well bore fluid is being lost or pressurized fluid is flowing into a drilled well bore interval or that the pressure containment integrity of the well bore interval is inadequate, well logs and other relevant well bore data are collected in the drilled well bore interval to diagnose the cause and extent of the well bore fluid loss, the pressurized formation fluid inflow or the inadequate pressure integrity containment. In a preferred technique, the collection of the relevant well data in the drilled well bore interval is accomplished in real time and the real time data is transmitted to a location where a specific treatment using a specific pumpable sealing composition is determined. Thereafter, the specific pumpable sealing composition is provided at the well site and the sealing composition is pumped into the drilled well bore interval.

The objects, features and advantages of the present invention will be readily apparent to those skilled in the art upon a reading of the description of preferred embodiments which follows.

DESCRIPTION OF PREFERRED EMBODIMENTS

In the drilling of wells, subterranean zones are often encountered which contain high incidences of weak zones, natural fractures, faults, high permeability streaks and the like through which well bore fluid outflows and pressurized formation fluid inflows can take place. As a result, drilling fluid circulation is sometimes lost which requires termination of the drilling operation. In addition to lost circulation, pressurized fluid inflows are often encountered which cause cross-flows or underground blow-outs whereby formation fluids flow into the well bore. These problems which may be undetectable at the surface often force the discontinuance of drilling operations and the implementation of remedial procedures that are of long duration and high cost.

A variety of methods and compositions have been developed and used for dealing with the above described problems. Unfortunately those methods and compositions are often unsatisfactory. Even when successful, adequate increases in the pressure containment integrity of the well bore are often not achieved. Prior to the present invention there has not been an effective technique available for discovering, diagnosing and correcting subterranean formation integrity problems of the types described above during the drilling of the well bore.

In order to prevent the high cost and down time associated with remedial procedures to restore lost circulation or solve other well bore problems, drilling rig operators are often forced to divert from their initial drilling plan. For example, the rig operators are frequently required to prematurely set casing in order to avoid well bore fluid outflows, pressurized formation fluid inflows and pressure containment integrity problems. These measures increase the cost of well construction, increase the time to completion and may also limit the well productivity due to restricted pipe diameters, the inability to reach desired reservoir depths and the like.

The methods of the present invention allow rig operators to discover, diagnose and correct formation integrity problems in successively drilled subterranean well bore intervals. That is, after drilling each well bore interval having a length in the range of from about 200 feet to about 5,000 feet, the drilling is temporarily stopped while tests are run and well log and other relevant well bore data is collected. If the test results and collected data indicate that one or more problems exist in the drilled well bore interval, remedial steps are taken to correct the problems after which the next well bore interval is drilled, tested, data collected, etc. This process of well bore interval drilling and discovering, diagnosing, and correcting formation integrity problems in each well bore interval is continued until the total well bore depth is reached. Thereafter, the well bore can be completed and placed on production without the occurrence of problems associated with formation integrity.

A method of this invention for discovering, disclosing and correcting formation integrity problems in successively drilled subterranean well bore intervals is comprised of the steps of: (a) determining if well bore fluid is being lost from each drilled well bore interval or if pressurized formation fluid is flowing into each well bore interval, or both; (b) determining the pressure containment integrity of each well bore interval; (c) if it is determined that well bore fluid is being lost from a well bore interval or pressurized formation fluid is flowing into the well bore interval, or both, in step (a) or if it is determined

that the pressure containment integrity is inadequate in step (b), providing a pumpable sealing composition for sealing the drilled well bore interval to prevent well bore fluid loss therefrom or pressurized formation fluid inflow thereinto or to increase the pressure containment integrity of the drilled well bore interval; and (d) pumping the sealing composition into the drilled well bore interval to cause the drilled well bore interval to be sealed or the pressure containment integrity of the drilled well bore interval to be increased, or both.

Before beginning the well bore drilling process, all well log data and other relevant well data relating to previous wells drilled in the area are studied and reviewed to determine problem areas that may be encountered and possible solutions for correcting the problems upon commencing the drilling of the new well bore.

After drilling the first well bore interval in accordance with the above described method, drilling is terminated and step (a) is conducted. That is, a test is conducted in the drilled well bore interval to determine if well bore fluid is being lost or if pressurized formation fluid is flowing into the well bore interval, or both. This test can be conducted by circulating a well bore fluid such as the drilling fluid in the well bore through the drilled well bore interval for a period of time sufficient to determine if the quantity of the well bore fluid being circulated decreases due to well bore fluid being lost from the drilled well bore interval or increases due to formation fluid which can be liquid or gas flowing into the well bore interval.

If the test conducted in accordance with step (a) is negative, the pressure containment integrity of the drilled well bore interval is determined in accordance with step (b). That is, a well bore fluid such as drilling fluid in the drilled well bore interval is increased in density or pressurized to an equivalent well bore fluid weight greater than or equal to the maximum hydrostatic pressure and friction pressure level expected to be exerted in the drilled well bore interval to determine if the pressure containment integrity of the drilled well bore interval is inadequate. That is, if the well bore fluid in the drilled well bore interval leaks off into the subterranean formation containing the well bore interval at the maximum equivalent well bore fluid weight, the pressure containment integrity of the well bore interval is inadequate. If the tests conducted in steps (a) and (b) are negative, i.e., if it is determined that no well bore fluid is being lost, no formation fluid is flowing into the well bore and the pressure containment integrity is adequate, drilling is resumed and the next well bore interval is drilled.

If, on the other hand, formation integrity problems are found by conducting steps (a) and (b) in the first well bore interval, steps (c) and (d) are conducted. However, before conducting steps (c) and (d), i.e., before providing the pumpable sealing composition and pumping it into the drilled well bore interval, electronic logs are run and all other relevant well bore data is collected in and relating to the drilled well bore interval. The collected data is analyzed in order to determine the extent of the weak zones and openings in the drilled well bore interval, the type of sealing composition required and the volume of the composition required. Examples of the data that can be collected and used include, but are not limited to, analyzing leak-off test data, electronic log data, formation cuttings, chemical composition analyses, and various simulation models well known to those skilled in the art. In addition to the type and volume of sealing composition required, the analysis determines the sealing composition placement parameters such as rates, pressures, volumes, time periods, densities, sealant properties, etc.

The sealing composition provided in accordance with step (c) of the method of this invention must seal the drilled well bore interval to prevent well bore fluid loss therefrom or fluid inflow thereinto or increase the pressure containment integrity of the drilled well bore interval, or both.

An example of a suitable sealing composition that can be used reacts with water in the drilled well bore interval and is basically comprised of oil, a hydratable polymer, an organophillic clay and a water swellable clay. This sealing composition is described in detail in U.S. Patent No. 6,060,434 issued to Sweatman et al. on May 9, 2000 which is incorporated herein by reference thereto.

The placement of the above described sealing composition can be controlled in a manner whereby portions of the sealing composition are continuously converted to sealing masses that are successively diverted into permeable portions of the drilled well bore interval until all of the permeable portions are sealed. This is accomplished by pumping the sealing composition through one or more openings at the end of a string of drill pipe into the drilled well bore interval at a flow rate relative to the well bore fluids therein whereby the sealing composition flows through the well bore fluids with a minimum of mixing therewith and whereby portions of the sealing composition are converted to sealing masses as the sealing composition flows through the interval. The sealing masses are successively diverted into and seal the weak zones and other permeable portions of the well bore interval through which

well bore fluids are flowing out of the zone thereby allowing the hydrostatic pressure exerted in the interval to increase until all of the permeable outflow portions in the interval are sealed. This method of utilizing a sealing composition is described in detail in U.S. Patent No. 5,913,364 to Sweatman issued on June 22, 1999 which is incorporated herein by reference thereto.

Another pumpable sealing composition which can be used reacts with oil in the drilled well bore interval and is basically comprised of water, an aqueous rubber latex, an organophillic clay, sodium carbonate and a hydratable polymer. This sealing composition is described in detail in U.S. Patent No. 6,258,757 B1 issued to Sweatman et al. on July 10, 2001 and is also incorporated herein by reference thereto.

As is well understood by those skilled in the art, a variety of other pumpable sealing compositions can be utilized in accordance with this invention to terminate well bore weak zones and/or openings allowing well bore fluid outflows, pressurized formation fluid inflows, well bore inadequate pressure containment integrity, and the like.

As will be further understood by those skilled in the art, spacers can be pumped into the drilled well bore interval in front of and/or behind the sealing composition utilized to prevent the sealing composition from reacting and solidifying before it reaches the weak zones and/or openings to be sealed. The spacers can have densities equal to or less than the density of the well fluid and the spacers can be chemically inhibited to prevent formation damage.

After the sealing composition has been placed in the drilled well bore interval, the well fluid containing sealing composition masses that have not been diverted into weak zones or openings in the formation being sealed is removed from the well bore. Thereafter, the drilled well bore interval can again be tested for pressure containment integrity to insure that the well bore interval was properly sealed. In addition, additional electric log data and other data can be collected to determine if the well bore interval has been satisfactorily sealed. Thereafter, drilling is commenced, another drilled well bore interval is produced and the above described tests and procedures implemented as necessary.

Another method of this invention for discovering, diagnosing and correcting formation integrity problems in successively drilled subterranean well bore intervals comprises the steps of: (a) drilling a first well bore interval; (b) determining if well bore fluid is being lost from the first well bore interval or if pressurized formation fluid is flowing into

the first well bore interval; (c) determining the pressure containment integrity of the first well bore interval; (d) if it is determined that well bore fluid is being lost from or pressurized formation fluid is flowing into the first well bore interval in step (b) or if it is determined that the pressure containment integrity is inadequate in the first well bore interval in step (c), or both, performing the additional steps of: (1) running well bore logs and collecting other relevant well bore data in the first well bore interval in real time, (2) transmitting all real time data collected to a location where a specific treatment using a specific pumpable sealing composition is determined, (3) providing the specific pumpable sealing composition at the well site, and (4) performing the specific treatment including pumping the sealing composition into the first well bore interval to cause the first well bore interval to be sealed or the pressure containment integrity to be increased, or both; and (e) repeating steps (a), (b), (c) and (d) for each additional well bore interval drilled until the total well bore depth is reached.

The above described method differs from the method previously described primarily in step (d) which calls for the relevant well bore data to be in real time, transmitting the real time data to a location where a specific treatment using a specific pumpable sealing composition is determined, providing the specific pumpable sealing composition at the well site and performing the specific treatment including pumping the sealing composition into the well bore interval to cause the well bore interval to be sealed or the pressure containment integrity to be increased or both.

As is well understood by those skilled in the art, oil and gas wells are often drilled at remote onshore well sites and offshore well sites. It is difficult for the personnel at the well site to analyze the data and to determine the specific treatment required using a specific pumpable sealing composition. In accordance with the method of this invention, the collected data is transmitted in real time to a remote location where the necessary computers and other equipment as well as trained personnel are located. The trained personnel can quickly determine the specific treatment required including placement parameters such as rates, pressures, volumes, time periods, densities, sealing properties and the like. Consequently, a specific treatment using a specific pumpable sealing composition is quickly determined and transmitted to the personnel at the well site so that the proper sealing composition can be quickly provided and the treatment can be carried out.

Thus the methods of the present invention avoid the various problems encountered by rig operators heretofore. The methods allow formation integrity problems to be discovered,

diagnosed and corrected during the drilling of the well bore so that when total depth is achieved, the resulting well bore is devoid of weak zones and openings and has adequate pressure containment integrity to permit well completion procedures to be carried out without the occurrence of costly and time consuming formation integrity problems.

Thus, the present invention is well adapted to carry out the objects and attain the benefits and advantages mentioned as well as those which are inherent therein. While numerous changes to the methods can be made by those skilled in the art, such changes are encompassed within the spirit of this invention as defined by the appended claims.

What is claimed is:

1. A method of discovering, diagnosing and correcting formation integrity problems in successively drilled subterranean well bore intervals comprising the steps of:

(a) determining if well bore fluid is being lost from each drilled well bore interval or if pressurized formation fluid is flowing into each well bore interval, or both;

(b) determining the pressure containment integrity of each well bore interval;

(c) if it is determined that well bore fluid is being lost from a well bore interval or pressurized formation fluid is flowing into said well bore interval, or both, in step (a) or if it is determined that said pressure containment integrity is inadequate in step (b), providing a pumpable sealing composition for sealing said drilled well bore interval to prevent well bore fluid outflow therefrom, to prevent pressurized formation fluid inflow thereinto or to increase the pressure containment integrity of said drilled well bore interval; and

(d) pumping said sealing composition into said drilled well bore interval to cause said drilled well bore interval to be sealed or the pressure containment integrity of said drilled well bore interval to be increased, or both.

2. The method of claim 1 wherein step (a) comprises circulating a well bore fluid through said drilled well bore interval for a period of time sufficient to determine if the quantity of said well bore fluid being circulated decreases due to well bore fluid outflow from said drilled well bore interval or increases due to pressurized formation fluid inflow into said drilled well bore interval.

3. The method of claim 2 wherein said well bore fluid is drilling fluid.

4. The method of claim 1 wherein if it is determined that well bore fluid outflow from said drilled well bore interval is occurring or pressurized formation fluid inflow into said drilled well bore interval is occurring, or both, step (a) further comprises analyzing well logs and other relevant well bore data collected in said drilled well bore interval to diagnose the cause and extent of said well bore fluid outflow or formation fluid inflow, or both.

5. The method of claim 1 wherein step (b) comprises increasing the density of or pressure exerted on a well bore fluid in said drilled well bore interval to an equivalent well bore fluid weight greater than or equal to the maximum hydrostatic pressure and friction pressure level to be exerted in said drilled well bore interval to determine if leak off occurs and the pressure containment integrity of said drilled well bore interval is inadequate.

6. The method of claim 5 wherein said well bore fluid is drilling fluid.

7. The method of claim 5 wherein if the pressure containment integrity is inadequate, step (b) further comprises analyzing well logs and other relevant well bore data collected in said drilled well bore interval to diagnose the cause and extent of said inadequate pressure integrity containment.

8. The method of claim 1 wherein when a pumpable sealing composition is provided in step (c), the pumpable sealing composition has the properties of rapidly converting into high viscosity sealing masses upon commingling and reacting with well bore fluids which are diverted into, seal and strengthen weak zones and openings in the drilled well bore interval through which well bore fluid outflows or pressurized formation fluid inflows into said drilled well bore interval.

9. The method of claim 1 wherein said pumpable sealing composition reacts with water in said drilled well bore interval and is comprised of oil, a hydratable polymer, an organophillic clay and a water swellable clay.

10. The method of claim 1 wherein said pumpable sealing composition reacts with oil in said drilled well bore interval and is comprised of water, an aqueous rubber latex, an organophillic clay, sodium carbonate and a hydratable polymer.

11. A method of discovering, diagnosing and correcting formation integrity problems in successively drilled subterranean well bore intervals comprising the steps of:

(a) drilling a first well bore interval;

(b) determining if well bore fluid is outflowing from said first drilled well bore interval or if pressurized formation fluid is inflowing into said first drilled well bore interval;

(c) determining the pressure containment integrity of said first drilled well bore interval;

(d) if it is determined that well bore fluid is outflowing or pressurized formation fluid is inflowing into said first drilled well bore interval in step (b) or if it is determined that said pressure containment integrity is inadequate in said first drilled well bore interval in step (c), or both, performing the additional steps of:

(1) running well bore logs and collecting other relevant well bore data in said first well bore interval in real time,

(2) transmitting all real time data collected to a location where a specific treatment using a specific pumpable sealing composition is determined,

(3) providing said specific pumpable sealing composition at said well site, and

(4) performing said specific treatment including pumping said sealing composition into said first drilled well bore interval to cause said first drilled well bore interval to be sealed or the pressure containment integrity to be increased, or both; and

(e) repeating steps (a), (b), (c) and (d) for each additional drilled well bore interval until the total well bore depth is reached.

12. The method of claim 11 wherein step (b) comprises circulating a well bore fluid through said drilled well bore interval for a period of time sufficient to determine if the quantity of said well bore fluid being circulated decreases due to well bore fluid outflow from said drilled well bore interval or increases due to pressurized formation fluid inflow into said drilled well bore interval.

13. The method of claim 12 wherein said well bore fluid is drilling fluid.

14. The method of claim 11 wherein if it is determined that well bore fluid outflow from said drilled well bore interval is occurring or pressurized formation fluid inflow into said drilled well bore interval is occurring, or both, step (b) further comprises analyzing well logs and other relevant well bore data collected in said drilled well bore interval to diagnose the cause and extent of said well bore fluid outflow or formation fluid inflow, or both.

15. The method of claim 11 wherein step (c) comprises increasing the density of or pressure exerted on a well bore fluid in said drilled well bore interval to an equivalent well bore fluid weight greater than or equal to the maximum hydrostatic pressure and friction pressure level to be exerted in said drilled well bore interval to determine if the pressure containment integrity of said drilled well bore interval is inadequate.

16. The method of claim 15 wherein said well bore fluid is drilling fluid.

17. The method of claim 15 wherein if the pressure containment integrity is inadequate, step (c) further comprises analyzing well logs and other relevant well bore data collected in said drilled well bore interval to diagnose the cause and extent of said inadequate pressure integrity containment.

18. The method of claim 11 wherein when a pumpable sealing composition is provided in accordance with step (d)(3), the pumpable sealing composition has the properties of rapidly converting into high viscosity sealing masses upon commingling and reacting with well bore fluids which are diverted into, seal and strengthen weak zones and openings in the drilled well bore interval through which well bore fluid outflows or pressurized formation fluid inflows into said drilled well bore interval.

19. The method of claim 11 wherein said pumpable sealing composition reacts with water in said drilled well bore interval and is comprised of oil, a hydratable polymer, an organophillic clay and a water swellable clay.

20. The method of claim 11 wherein said pumpable sealing composition reacts with oil in said drilled well bore interval and is comprised of water, an aqueous rubber latex, an organophillic clay, sodium carbonate and a hydratable polymer.

INTERNATIONAL SEARCH REPORT

PCT/GB 03/00775

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B21/00 E21B21/08

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
P,Y	US 2002/112888 A1 (LEUCHTENBERG CHRISTIAN) 22 August 2002 (2002-08-22) page 3, paragraph 33 -page 4, paragraph 45 ---	1,11
Y	US 4 498 995 A (GOCKEL JUDITH) 12 February 1985 (1985-02-12) column 2, line 7 -column 2, line 48 ---	1,11
A	KELLEY S ET AL: "DRILL AHEAD TO COMPLETE HP/HT WELLS A NEW PROCESS HELPS MAINTAIN BORHEOLE PRESSURE INTEGRITY" PETROLEUM ENGINEER INTERNATIONAL, HART PUBLICATIONS, US, vol. 74, no. 9, September 2001 (2001-09), pages 87-88,91, XP001087096 ISSN: 0164-8322 the whole document ---	1,11

-/--

[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

° Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier document but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
26 June 2003	08/07/2003
Name and mailing address of the ISA European Patent Office, P.B. 5818 Patentlaan 2 NL – 2280 HV Rijswijk Tel. (+31–70) 340–2040, Tx. 31 651 epo nl, Fax: (+31–70) 340–3016	Authorized officer Morrish, S

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	KUROCHKIN B: "CLAY/LATEX MIXTURE STOPS LOST CIRCULATION IN LARGE CARBONATE FRACTURE" OIL AND GAS JOURNAL, PENNWELL PUBLISHING CO. TULSA, US, vol. 93, no. 35, 28 August 1995 (1995-08-28), pages 92-93, XP000534283 ISSN: 0030-1388 the whole document	1,11

INTERNATIONAL SEARCH REPORT

PCT/GB 03/00775

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2002112888 A1	22-08-2002	AU 1932202 A	01-07-2002
		WO 0250398 A1	27-06-2002
		US 2003079912 A1	01-05-2003
US 4498995 A	12-02-1985	US 4460052 A	17-07-1984

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
28 August 2003 (28.08.2003)

PCT

(10) International Publication Number
WO 03/071091 A1

(51) International Patent Classification[7]: E21B 21/08, 44/00

(21) International Application Number: PCT/US03/05012

(22) International Filing Date: 19 February 2003 (19.02.2003)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
60/358,226 20 February 2002 (20.02.2002) US

(71) Applicants: SHELL OIL COMPANY [US/US]; 910 Louisiana Street, P.O. Box 2463, Houston, TX 77002-2463 (US). SHELL CANADA LIMITED [CA/CA]; 400-4TH Avenue, S.W., Calgary, Alberta T2P 2H5 (CA).

(72) Inventor: VAN RIET, Egbert, Jan; Volmerlaan 8, NL-2288, NL-NL-2288 Rijswijk (NL).

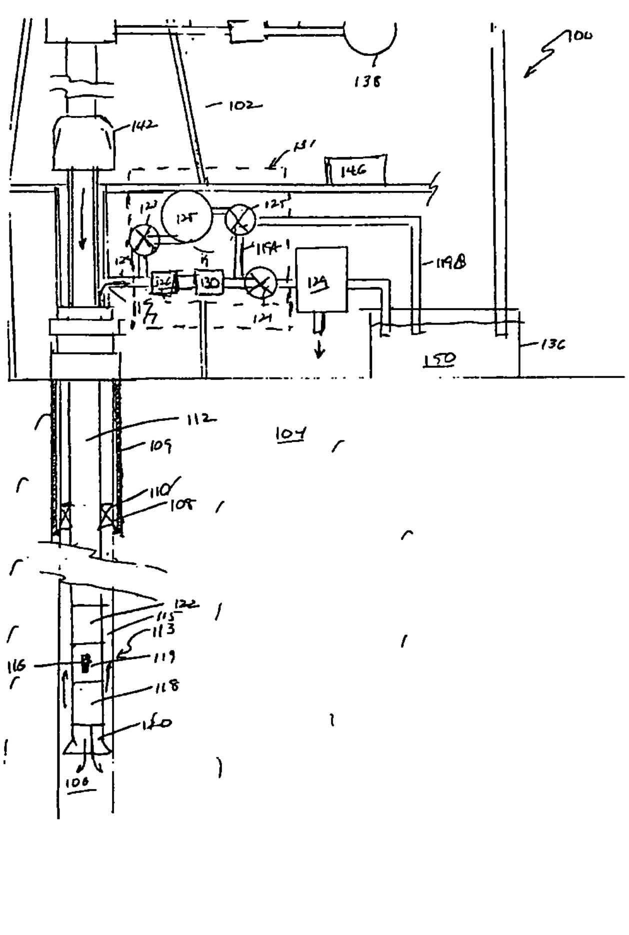
(74) Agent: MONTALVO, Eugene, R.; SHELL OIL COMPAPNY, 910 Louisiana Street, P.O. Box 2463, Houston, TX 77002-2463 (US).

(81) Designated States *(national)*: AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EC, EE, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NO, NZ, OM, PH, PL, PT, RO, RU, SC, SD, SE, SG, SK, SL, TJ, TM, TN, TR, TT, TZ, UA, UG, UZ, VC, VN, YU, ZA, ZM, ZW.

(84) Designated States *(regional)*: ARIPO patent (GH, GM, KE, LS, MW, MZ, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HU, IE, IT, LU, MC, NL, PT, SE, SI, SK, TR), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

[Continued on next page]

(54) Title: DYNAMIC ANNULAR PRESSURE CONTROL APPARATUS AND METHOD



(57) **Abstract:** A system and method for controlling formation pressures during drilling of a subterranean formation utilizing a selectively fluid backpressure system in which fluid is pumped down the drilling fluid return system in response to detected borehole pressures. A pressure monitoring system is further provided to monitor detected borehole pressures, model expected borehole pressures for further drilling and control the fluid backpressure system.

WO 03/071091 A1

Published:

- *with international search report*
- *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments*

For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

DYNAMIC ANNULAR PRESSURE CONTROL APPARATUS AND METHOD

Field of the Invention

The present method and apparatus are related to a method for dynamic well borehole annular pressure control, more specifically, a selectively closed-loop, pressurized method for controlling borehole pressure during drilling and other well completion operations.

Background of the Art

The exploration and production of hydrocarbons from subsurface formations ultimately requires a method to reach and extract the hydrocarbons from the formation. This is typically done with a drilling rig. In its simplest form, this constitutes a land-based drilling rig that is used to support a drill bit mounted on the end of drill string, comprised of a series of drill tubulars. A fluid comprised of a base fluid, typically water or oil, and various additives are pumped down the drill string, and exits through the rotating drill bit. The fluid then circulates back up the annulus formed between the borehole wall and the drill bit, taking with it the cuttings from the drill bit and clearing the borehole. The fluid is also selected such that the hydrostatic pressure applied by the fluid is greater than surrounding formation pressure, thereby preventing formation fluids from entering into the borehole. It also causes the fluid to enter into the formation pores, or "invade" the formation. Further, some of the additives from the pressurized fluid adhere to the formation walls forming a "mud cake" on the formation walls. This mud cake helps to preserve and protect the formation prior to the setting of casing in the drilling process, as will be discussed further below. The selection of fluid pressure in excess of formation pressure is commonly referred to as over balanced drilling. The fluid then returns to the surface, where it is bled off into a mud system, generally comprised of a shaker table, to remove solids, a mud pit and a manual or automatic means for addition of various chemicals or additives to the returned fluid. The clean, returned fluid flow is measured to determine fluid losses to the formation as a result of fluid invasion. The returned solids and fluid (prior to treatment) may be studied to determine various formation characteristics used in drilling operations. Once the fluid has been treated in the mud pit, it is then pumped out of the mud pit and re-injected into the top of the drill string again.

This overbalanced technique is the most commonly used fluid pressure control method. It relies primarily on the fluid density and hydrostatic force generated by the column of fluid in the annulus to generate pressure. By exceeding the formation pore pressure, the fluid is used to prevent sudden releases of formation fluid to the borehole, such as gas kicks. Where such gas kicks occur, the density of the fluid may be increased to prevent further formation fluid release to the borehole. However, the addition of weighting additives to increase fluid density (a) may not be rapid enough to deal with the formation fluid release and (b) may exceed the formation fracture pressure, resulting in the creation of fissures or fractures in the formation, with resultant fluid loss to the formation, possibly adversely affecting near borehole permeability. In such events, the operator may elect to close the blow out preventors (BOP) below the drilling rig floor to control the movement of the gas up the annulus. The gas is bled off and the fluid density is increased prior to resuming drilling operations.

The use of overbalanced drilling also affects the selection of casing during drilling operations. The drilling process starts with a conductor pipe being driven into the ground, a BOP stack attached to the drilling conductor, with the drill rig positioned above the BOP stack. A drill string with a drill bit may be selectively rotated by rotating the entire string using the rig kelly or a top drive, or may be rotated independent of the drill string utilizing drilling fluid powered mechanical motors installed in the drill string above the drill bit. As noted above, an operator may drill open hole for a period until such time as the accumulated fluid pressure at a calculated depth nears that of the formation fracture pressure. At that time, it is common practice to insert and hang a casing string in the borehole from the surface down to the calculated depth. A cementing shoe is placed on the drill string and specialized cement is injected into the drill string, to travel up the annulus and displace any fluid then in the annulus. The cement between the formation wall and the outside of the casing effectively supports and isolates the formation from the well bore annulus and further open hole drilling is carried out below the casing string, with the fluid again providing pressure control and formation protection.

Fig. 1 is an exemplary diagram of the use of fluids during the drilling process in an intermediate borehole section. The top horizontal bar represents the hydrostatic pressure exerted by the drilling fluid and the vertical bar represents the total vertical depth of the borehole. The formation pore pressure graph is represented by line 10. As noted above, in an over balanced situation, the fluid pressure exceeds the formation pore pressure for reasons of pressure control and hole stability. Line 12 represents the formation fracture

pressure. Pressures in excess of the formation fracture pressure will result in the fluid pressurizing the formation walls to the extent that small cracks or fractures will open in the borehole wall and the fluid pressure overcomes the formation pressure with significant fluid invasion. Fluid invasion can result in reduced permeability, adversely affecting formation production. The annular pressure generated by the fluid and its additives is represented by line 14 and is a linear function of the total vertical depth. The pure hydrostatic pressure that would be generated by the fluid, less additives, i.e., water, is represented by line 16.

In an open loop fluid system described above, the annular pressure seen in the borehole is a linear function of the borehole fluid. This is true only where the fluid is at a static density. While the fluid density may be modified during drilling operations, the resulting pressure annular pressure is generally linear. In Fig. 1, the hydrostatic pressure 16 and the pore pressure 10 generally track each other in the intermediate section to a depth of approximately 7000 feet. Thereafter, the pore pressure 10 increases in the interval from a depth of 7000 feet to approximately 9300 feet. This may occur where the borehole penetrates a formation interval having significantly different characteristics than the prior formation. The annular pressure 14 maintained by the fluid 14 is safely above the pore pressure prior to 7000 feet. In the 7000 – 9300 foot interval, the differential between the pore pressure 10 and annular pressure 14 is significantly reduced, decreasing the margin of safety during operations. A gas kick in this interval may result in the pore pressure exceeding the annular pressure with a release of fluid and gas into the borehole, possibly requiring activation of the surface BOP stack. As noted above, while additional weighting material may be added to the fluid, it will be generally ineffective in dealing with a gas kick due to the time required to increase the fluid density as seen in the borehole.

Fluid circulation itself also creates problems in an open system. It will be appreciated that it is necessary to shut off the mud pumps in order to make up successive drill pipe joints. When the pumps are shut off, the annular pressure will undergo a negative spike that dissipates as the annular pressure stabilizes. Similarly, when the pumps are turned back on, the annular pressure will undergo a positive spike. This occurs each time a pipe joint is added to or removed from the string. It will be appreciated that these spikes can cause fatigue on the borehole cake and could result in formation fluids entering the borehole, again leading to a well control event.

In contrast to open fluid circulation systems, there have been developed a number of closed fluid handling systems. Examples of these include U.S. Patents 5,857,522 and 6,035,952, both to Bradfield et al. and assigned to Baker Hughes Incorporated. In these patents, a closed system is used for the purposes of underbalanced drilling, i.e., the annular pressure is less than that of the formation pore pressure. Underbalanced drilling is generally used where the formation is a chalk or other fractured limestone and the desire is to prevent the mud cake from plugging fractures in the formation. Moreover, it will be appreciated that where underbalanced systems are used, a significant well event will require that the BOPs be closed to handle the kick or other sudden pressure increase.

Other systems have been designed to maintain fluid circulation during the addition or removal of additional drill string tubulars (make/break). In U.S. Patent 6,352,129, assigned to Shell Oil Company, assignee of the present invention, a continuous circulation system is shown whereby the make up/break operations and the separate pipe sections are isolated from each other in a fluid chamber 20 and a secondary conduit 28 is used to supply pumped fluid to that portion of the drill string 12 still in fluid communications with the formation. In a second implementation, the publication discloses an apparatus and method for injecting a fluid or gas into the fluid stream after the pumps have been turned off to maintain and control annular pressure.

Summary of the Present Invention

The present invention is directed to a closed loop, overbalanced drilling system having a variable overbalance pressure capability. The present invention further utilizes information related to the wellbore, drill rig and drilling fluid as inputs to a model to predict downhole pressure. The predicted downhole pressure is then compared to a desired downhole pressure and the differential is utilized to control a backpressure system. The present invention further utilizes actual downhole pressure to calibrate the model and modify input parameters to more closely correlate predicted downhole pressures to measured downhole pressures.

In one aspect, the present invention is capable of modifying annular pressure during circulation by the addition of backpressure, thereby increasing the annular pressure without the addition of weighting additives to the fluid. It will be appreciated that the use of backpressure to increase annular pressure is more responsive to sudden changes in formation pore pressure.

In yet another aspect, the present invention is capable of maintaining annular pressure during pump shut down when drill pipe is being added to or removed from the

string. By maintaining pressure in the annulus, the mud cake build up on the formation wall is maintained and does not see sudden spikes or drops in annular pressure.

In yet another aspect, the present invention utilizes an accurate mass-balance flow meter that permits accurate determination of fluid gains or losses in the system, permitting the operator to better manage the fluids involve in the operation.

In yet another aspect, the present invention includes automated sensors to determine annular pressure, flow, and with depth information, can be used to predict pore pressure, allowing the present invention to increase annular pressure in advance of drilling through the section in question.

Brief Description of the Drawings

A better understanding of the present invention may be had by referencing the following drawings in conjunction with the Detailed Description of the Preferred Embodiment, in which

Figure 1 is a graph depicting annular pressures and formation pore and fracture pressures;

Figures 2A and 2B are plan views of two different embodiments of the apparatus of of the invention;

Figure 3 is a block diagram of the pressure monitoring and control system utilized in the preferred embodiment;

Figure 4 is a functional diagram of the operation of the pressure monitoring and control system;

Figure 5 is a graph depicting the correlation of predicted annular pressures to measured annular pressures;

Figure 6 is a graph depicting the correlation of predicted annular pressures to measured annular pressures depicted in Figure 5, upon modification of certain model parameters;

Figure 7 is a graph depicting how the method of the present invention may be used to control variations in formation pore pressure in an overbalanced condition;

Figure 8 is a graph depicting the method of the present invention as applied to at balanced drilling; and

Figures 9A and 9B are graphs depicting how the present invention may be used to counteract annular pressure drops and spikes that accompany pump off/pump on conditions.

Detailed Description of the Preferred Embodiment

The present invention is intended to achieve Dynamic Annulus Pressure Control (DAPC) of a well bore during drilling and intervention operations.

Structure of the Preferred Embodiment

Figure 2A is a plan view depicting a surface drilling system employing the current invention. It will be appreciated that an offshore drilling system may likewise employ the current invention. The drilling system 100 is shown as being comprised of a drilling rig 102 that is used to support drilling operations. Many of the components used on a rig 102, such as the kelly, power tongs, slips, draw works and other equipment are not shown for ease of depiction. The rig 102 is used to support drilling and exploration operations in formation 104. As depicted in Fig. 2 the borehole 106 has already been partially drilled, casing 108 set and cemented 109 into place. In the preferred embodiment, a casing shutoff mechanism, or downhole deployment valve, 110 is installed in the casing 108 to optionally shutoff the annulus and effectively act as a valve to shut off the open hole section when the bit is located above the valve.

The drill string 112 supports a bottom hole assembly (BHA) 113 that includes a drill bit 120, a mud motor 118, a MWD/LWD sensor suite 119, including a pressure transducer 116 to determine the annular pressure, a check valve, to prevent backflow of fluid from the annulus. It also includes a telemetry package 122 that is used to transmit pressure, MWD/LWD as well as drilling information to be received at the surface . While Fig. 2A illustrates a BHA utilizing a mud telemetry system, it will be appreciated that other telemetry systems, such as radio frequency (RF), electromagnetic (EM) or drilling string transmission systems may be employed within the present invention. .

As noted above, the drilling process requires the use of a drilling fluid 150, which is stored in reservoir 136. The reservoir 136 is in fluid communications with one or more mud pumps 138 which pump the drilling fluid 150 through conduit 140. The conduit 140 is connected to the last joint of the drill string 112 that passes through a rotating or spherical BOP 142. A rotating BOP 142, when activated, forces spherical shaped elastomeric elements to rotate upwardly, closing around the drill string 112, isolating the pressure, but still permitting drill string rotation. Commercially available spherical BOPs, such as those manufactured by Varco International, are capable of isolating annular pressures up to 10,000 psi (68947.6 kPa). The fluid 150 is pumped down through the drill string 112 and the BHA 113 and exits the drill bit 120, where it circulates the cuttings away from the bit 120 and returns them up the open hole annulus 115 and then the annulus

formed between the casing 108 and the drill string 112. The fluid 150 returns to the surface and goes through diverter 117, through conduit 124 and various surge tanks and telemetry systems (not shown).

Thereafter the fluid 150 proceeds to what is generally referred to as the backpressure system 131. The fluid 150 enters the backpressure system 131 and flows through a flow meter 126. The flow meter 126 may be a mass-balance type or other high-resolution flow meter. Utilizing the flow meter 126, an operator will be able to determine how much fluid 150 has been pumped into the well through drill string 112 and the amount of fluid 150 returning from the well. Based on differences in the amount of fluid 150 pumped versus fluid 150 returned, the operator is be able to determine whether fluid 150 is being lost to the formation 104, which may indicate that formation fracturing has occurred, i.e., a significant negative fluid differential. Likewise, a significant positive differential would be indicative of formation fluid entering into the well bore.

The fluid 150 proceeds to a wear resistant choke 130. It will be appreciated that there exist chokes designed to operate in an environment where the drilling fluid 150 contains substantial drill cuttings and other solids. Choke 130 is one such type and is further capable of operating at variable pressures and through multiple duty cycles. The fluid 150 exits the choke 130 and flows through valve 121. The fluid 150 is then processed by an optional degasser 1 and by a series of filters and shaker table 129, designed to remove contaminates, including cuttings, from the fluid 150. The fluid 150 is then returned to reservoir 136. A flow loop 119A, is provided in advance of valve 125 for feeding fluid 150 directly a backpressure pump 128. Alternatively, the backpressure pump 128 may be provided with fluid from the reservoir through conduit 119B, which is fluid communications with the reservoir 1 (trip tank). The trip tank is normally used on a rig to monitor fluid gains and losses during tripping operations. In the this invention, this functionality is maintained. A three-way valve 125 may be used to select loop 119A, conduit 119B or isolate the backpressure system. While backpressure pump 128 is capable of utilizing returned fluid to create a backpressure by selection of flow loop 119A, it will be appreciated that the returned fluid could have contaminates that have not been removed by filter/shaker table 129. As such, the wear on backpressure pump 128 may be increased. As such, the preferred fluid supply to create a backpressure would be to use conduit 119A to provide reconditioned fluid to backpressure pump 128.

In operation, valve 125 would select either conduit 119A or conduit 119B, and the backpressure pump 128 engaged to ensure sufficient flow passes the choke system to be

able to maintain backpressure, even when there is no flow coming from the annulus 115. In the preferred embodiment, the backpressure pump 128 is capable of providing up to approximately 2200 psi (15168.5 kPa) of backpressure; though higher pressure capability pumps may be selected.

The ability to provide backpressure is a significant improvement over normal fluid control systems. The pressure in the annulus provided by the fluid is a function of its density and the true vertical depth and is generally a by approximation linear function. As noted above, additives added to the fluid in reservoir 136 must be pumped downhole to eventually change the pressure gradient applied by the fluid 150.

The preferred embodiment of the present invention further includes a flow meter 152 in conduit 100 to measure the amount of fluid being pumped downhole. It will be appreciated that by monitoring flow meters 126, 152 and the volume pumped by the backpressure pump 128, the system is readily able to determine the amount of fluid 150 being lost to the formation, or conversely, the amount of formation fluid leaking to the borehole 106. Further included in the present invention is a system for monitoring well pressure conditions and predicting borehole 106 and annulus 115 pressure characteristics.

Figure 2B depicts an alternative embodiment of the system. In this embodiment the backpressure pump is not required to maintain sufficient flow through the choke system when the flow through the well needs to be shut off for any reason. In this embodiment, an additional three way valve 6 is placed downstream of the rig pump 138 in conduit 140. This valve allows fluid from the rig pumps to be completely diverted from conduit 140 to conduit 7, not allowing flow from the rig pump 138 to enter the drill string 112. By maintaining pump action of pump 138, sufficient flow through the manifold to control backpressure is ensured.

<u>DAPC Monitoring System</u>

Figure 3 is a block diagram of the pressure monitoring system 146 of the preferred embodiment of the present invention. System inputs to the monitoring system 146 include the downhole pressure 202 that has been measured by sensor package119, transmitted by MWD pulser package 122 and received by transducer equipment (not shown) on the surface. Other system inputs include pump pressure 200, input flow 204 from flow meter 152, penetration rate and string rotation rate, as well as weight on bit (WOB) and torque on bit (TOB) that may be transmitted from the BHA 113 up the annulus as a pressure pulse. Return flow is measured using flow meter 126. Signals representative of the data inputs are transmitted to a control unit 230, which is it self comprised of a drill rig control

unit 232, a drilling operator's station 234, a DAPC processor 236 and a back pressure programmable logic controller (PLC) 238, all of which are connected by a common data network 240. The DAPC processor 236 serves three functions, monitoring the state of the borehole pressure during drilling operations, predicting borehole response to continued drilling, and issuing commands to the backpressure PLC to control the variable choke 130 and backpressure pump 128. The specific logic associated with the DAPC processor 236 will be discussed further below.

Calculation of Backpressure

A schematic model of the functionality of the DAPC pressure monitoring system 146 is set forth in Figure 4. The DAPC processor 236 includes programming to carry out Control functions and Real Time Model Calibration functions. The DAPC processor receives data from various sources and continuously calculates in real time the correct backpressure set-point based on the input parameters. The set-point is then transferred to the programmable logic controller 238, which generates the control signals for backpressure pump 128. The input parameters fall into three main groups. The first are relatively fixed parameters 250, including parameters such as well and casing string geometry, drill bit nozzle diameters, and well trajectory. While it is recognized that the actual well trajectory may vary from the planned trajectory, the variance may be taken into account with a correction to the planned trajectory. Also within this group of parameters are temperature profile of the fluid in the annulus and the fluid composition. As with the trajectory parameters, these are generally known and do not change over the course of the drilling operations. In particular, with the DAPC system, one objective is keeping the fluid 150 density and composition relatively constant, using backpressure to provide the additional pressure to control the annulus pressure.

The second group of parameters 252 are variable in nature and are sensed and logged in real time. The common data network 240 provides this information to the DAPC processor 236. This information includes flow rate data provided by both downhole and return flow meters 152 and 126, respectively, the drill string rate of penetration (ROP) or velocity, the drill string rotational speed, the bit depth, and the well depth, the latter two being derived from rig sensor data. The last parameter is the downhole pressure data 254 that is provided by the downhole MWD/LWD sensor suite 119 and transmitted back up the annulus by the mud pulse telemetry package 122. One other input parameters is the set-point downhole pressure 256, the desired annulus pressure.

The functionally the control module 258 attempts to calculate the pressure in the annulus over its fill well bore length utilizing various models designed for various formation and fluid parameters. The pressure in the well bore is a function not only of the pressure or weight of the fluid column in the well, but includes the pressures caused by drilling operations, including fluid displacement by the drill string, frictional losses returning up the annulus, and other factors. In order to calculate the pressure within the well, the control module 258 considers the well as a finite number of segments, each assigned to a segment of well bore length. In each of the segments the dynamic pressure and the fluid weight is calculated and used to determine the pressure differential 262 for the segment. The segments are summed and the pressure differential for the entire well profile is determined.

It is known that the flow rate of the fluid 150 being pumped downhole is proportional to the flow velocity of fluid 150 and may be used to determine dynamic pressure loss as the fluid is being pumped downhole. The fluid 150 density is calculated in each segment, taking into account the fluid compressibility, estimated cutting loading and the thermal expansion of the fluid for the specified segment, which is itself related to the temperature profile for that segment of the well. The fluid viscosity at the temperature profile for the segment is also instrumental in determining dynamic pressure losses for the segment. The composition of the fluid is also considered in determining compressibility and the thermal expansion coefficient. The drill string ROP is related to the surge and swab pressures encountered during drilling operations as the drill string is moved into or out of the borehole. The drill string rotation is also used to determine dynamic pressures, as it creates a frictional force between the fluid in the annulus and the drill string. The bit depth, well depth, and well/string geometry are all used to help create the borehole segments to be modeled. In order to calculate the weight of the fluid, the preferred embodiment considers not only the hydrostatic pressure exerted by fluid 150 , but also the fluid compression, fluid thermal expansion and the cuttings loading of the fluid seen during operations. It will be appreciated that the cuttings loading can be determined as the fluid is returned to the surface and reconditioned for further use. All of these factors go into calculation of the "static pressure".

Dynamic pressure considers many of the same factors in determining static pressure. However, it further considers a number of other factors. Among them is the concept of laminar versus turbulent flow. The flow characteristics are a function of the estimated roughness, hole size and the flow velocity of the fluid. The calculation also

considers the specific geometry for the segment in question. This would include borehole eccentricity and specific drill pipe geometry (box/pin upsets) that affect the flow velocity seen in the borehole annulus. The dynamic pressure calculation further includes cuttings accumulation downhole, as well as fluid rheology and the drill string movement's (penetration and rotation) effect on dynamic pressure of the fluid.

The pressure differential 262 for the entire annulus is calculated and compared to the set-point pressure 251 in the control module 264. The desired backpressure 266 is then determined and passed on to programmable logic controller 238, which generates control signals for the backpressure pump 128.

Calibration and Correction of the Backpressure

The above discussion of how backpressure is generally calculated utilized several downhole parameters, including downhole pressure and estimates of fluid viscosity and fluid density. These parameters are determined downhole and transmitted up the mud column using pressure pulses. Because the data bandwidth for mud pulse telemetry is very low and the bandwidth is used by other MWD/LWD functions, as well as drill string control functions, downhole pressure, fluid density and viscosity can not be input to the DAPC model on a real time basis. Accordingly, it will be appreciated that there is likely to be a difference between the measured downhole pressure, when transmitted up to the surface, and the predicted downhole pressure for that depth. When such occurs the DAPC system computes adjustments to the parameters and implements them in the model to make a new best estimate of downhole pressure. The corrections to the model may be made by varying any of the variable parameters. In the preferred embodiment, the fluid density and the fluid viscosity are modified in order to correct the predicted downhole pressure. Further, in the present embodiment the actual downhole pressure measurement is used only to calibrate the calculated downhole pressure. It is not utilized to predict downhole annular pressure response. If downhole telemetry bandwidth increases, it may then be practical to include real time downhole pressure and temperature information to correct the model.

Because there is a delay between the measurement of downhole pressure and other real time inputs, the DAPC control system 236 further operates to index the inputs such that real time inputs properly correlate with delayed downhole transmitted inputs. The rig sensor inputs, calculated pressure differential and backpressure pressures, as well as the downhole measurements, may be "time-stamped" or "depth-stamped" such that the inputs and results may be properly correlated with later received downhole data. Utilizing a

regression analysis based on a set of recently time-stamped actual pressure measurements, the model may be adjusted to more accurately predict actual pressure and the required backpressure.

Figure 5 depicts the operation of the DAPC control system demonstrating an uncalibrated DAPC model. It will be noted that the downhole pressure while drilling (PWD) 400 is shifted in time as a result of the time delay for the signal to be selected and transmitted uphole. As a result, there exists a significant offset between the DAPC predicted pressure 404 and the non-time stamped PWD 400. When the PWD is time stamped and shifted back in time 402, the differential between PWD 402 and the DAPC predicted pressure 404 is significantly less when compared to the non-time shifted PWD 400. Nonetheless, the DAPC predicted pressure differs significantly. As noted above, this differential is addressed by modifying the model inputs for fluid 150 density and viscosity. Based on the new estimates, in Fig. 6, the DAPC predicted pressure 404 more closely tracks the time stamped PWD 402. Thus, the DAPC model uses the PWD to calibrate the predicted pressure and modify model inputs to more accurately predict downhole pressure throughout the entire borehole profile.

Based on the DAPC predicted pressure, the DAPC control system 236 will calculate the required backpressure level 266 and transmit it to the programmable logic controller 240. The programmable controller 240 then generates the necessary control signals to choke 130, valves 121 and 123, and backpressure pump 128.

<u>Applications of the DAPC System</u>

The advantage in utilizing the DAPC backpressure system may be readily in the chart of Fig. 7. The hydrostatic pressure of the fluid is depicted in line 302. As may be seen, the pressure increases as a linear function of the depth of the borehole according to the simple formula:

$$P = \rho TVD + C \qquad [1]$$

Where P is the pressure, ρ is the fluid density, TVD is the total vertical depth of the well, and C is the backpressure. In the instance of hydrostatic pressure 302, the density is that of water. Moreover, in an open system, the backpressure C is zero. However, in order to ensure that the annular pressure 303 is in excess of the formation pore pressure 300, the fluid is weighted, thereby increasing the pressure applied as the depth increases. The pore pressure profile 300 can be seen in Fig. 7, linear, until such time as it exits casing 301, in which instance, it is exposed to the actual formation pressure, resulting in a sudden

increase in pressure. In normal operations, the fluid density must be selected such that the annular pressure 303 exceeds the formation pore pressure below the casing 301.

In contrast, the use of the DAPC permits an operator to make essentially step changes in the annular pressure. Multiple DAPC pressure lines 304, 306, 308 and 310 are depicted in Fig. 7. In response to the pressure increase seen in the pore pressure at 300b, the back pressure C may be increased to step change the annular pressure from 304 to 306 to 308 to 310 in response to increasing pore pressure 300b, in contrast with normal annular pressure techniques as depicted in line 303. The DAPC concept further offers the advantage of being able to decrease the back pressure in response to a decrease in pore pressure as seen in 300c. It will be appreciated that the difference between the DAPC maintained annular pressure 310 and the pore pressure 300c, known as the overbalance pressure, is significantly less than the overbalance pressure seen using conventional annular pressure control methods 303. Highly overbalanced conditions can adversely affect the formation permeability be forcing greater amounts of borehole fluid into the formation.

Figure 8 is a graph depicting one application of the DAPC system in an At Balance Drilling (ABD) environment. The situation in Fig. 8 depicts the pore pressure in an interval 320a as being fairly linear until approximately 2 km TVD, and as being kept in check by conventional annular pressure 321a. At 2 km TVD a sudden increase in pore pressure occurs at 320b. Utilizing present techniques, the answer would be to increase the fluid density to prevent formation fluid influx and sloughing off of the borehole mud cake. The resulting increase in density modifies the pressure profile applied by the fluid to 321b. However, in doing so it dramatically increases the overbalance pressure, not only in region 320c, but in region 320a as well.

Using the DAPC technique, the alternative response to the pressure increase seen at 320b, would be to apply backpressure to the fluid to shift the pressure profile to the right, such that pressure profile 322 more closely matches the pore pressure 320c, as opposed to pressure profile 321b.

The DAPC method of pressure control may also be used to control a major well event, such as a fluid influx. Under present methods, in the event of a large formation fluid influx, such as a gas kick, the only option was to close the BOPs to effectively to shut in the well, relieve pressure through the choke and kill manifold, and weight up the drilling fluid to provide additional annular pressure. This technique requires time to bring the well under control. An alternative method is sometimes called the "Driller's" method,

which utilizes continuous circulation without shutting in the well. A supply of heavily weighted fluid, e.g., 18 pounds per gallon (ppg) (3.157 kg/l) is constantly available during drilling operations below any set casing. When a gas kick or formation fluid influx is detected, the heavily weighted fluid is added and circulated downhole, causing the influx fluid to go into solution with the circulating fluid. The influx fluid starts coming out of solution upon reaching the casing shoe and is released through the choke manifold. It will be appreciated that while the Driller's method provides for continuous circulation of fluid, it may still require additional circulation time without drilling ahead, to prevent additional formation fluid influx and to permit the formation fluid to go into circulation with the now higher density drilling fluid.

Utilizing the present DAPC technique, when a formation fluid influx is detected, the backpressure is increased, as opposed to adding heavily weighted fluid. Like the Driller's method, the circulation is continued. With the increase in pressure, the formation fluid influx goes into solution in the circulating fluid and is released via the choke manifold. Because the pressure has been increased, it is no longer necessary to immediately circulate a heavily weighted fluid. Moreover, since the backpressure is applied directly to the annulus, it quickly forces the formation fluid to go into solution, as opposed to waiting until the heavily weighted fluid is circulated into the annulus.

An additional application of the DAPC technique relates to its use in non-continuous circulating systems. As noted above, continuous circulation systems are used to help stabilize the formation, avoiding the sudden pressure 502 drops that occurs when the mud pumps are turned off to make/break new pipe connections. This pressure drop 502 is subsequently followed by a pressure spike 504 when the pumps are turned back on for drilling operations. This is depicted in Fig. 9A. These variations in annular pressure 500 can adversely affect the borehole mud cake, and can result in fluid invasion into the formation. As shown in Fig. 9B, the DAPC system backpressure 506 may be applied to the annulus upon shutting off the mud pumps, ameliorating the sudden drop in annulus pressure from pump off condition to a more mild pressure drop 502. Prior to turning the pumps on, the backpressure may be reduced such that the pump on condition spike 504 is likewise reduced. Thus the DAPC backpressure system is capable of maintaining a relatively stable downhole pressure during drilling conditions. Although the invention has been described with reference to a specific embodiment, it will be appreciated that modifications may be made to the system and method described herein without departing from the invention.

WE CLAIM:

1. A system for controlling formation pressure during the drilling of a subterranean formation, comprising:

a drill string extending into a borehole, the drill string including a bottom hole assembly, the bottom hole assembly comprising, drill bit, sensors, and a telemetry system capable of receiving and transmitting data, including sensor data, said sensor data including at least pressure and temperature data;

a surface telemetry system for receiving data and transmitting commands to the bottom hole assembly;

a primary pump for selectively pumping a drilling fluid from a drilling fluid source, through said drill string, out said drill bit and into an annular space created as said drill string penetrates the formation;

a fluid discharge conduit in fluid communication with said annular space for discharging said drilling fluid to a reservoir to clean said drilling fluid for reuse;

a fluid backpressure system connected to said fluid discharge conduit; said fluid backpressure system comprised of a flow meter, a fluid choke, a backpressure pump, a fluid source, whereby said backpressure pump may be selectively activated to increase annular space drilling fluid pressure.

2. The system of claim 1, further including a pressure monitoring system, capable of receiving drilling operational data, said drilling operational data including drill string weight on bit, drill string torque on bit, drilling fluid weight, drilling fluid volume, primary and backpressure pump pressures, drilling fluid flow rates, drill string rate of penetration, drill string rotation rate, and sensor data transmitted by said bottom hole assembly.

3. The system of claim 2, wherein said pressure monitoring system utilizes said drilling operational data to

monitor existing said annular space pressures during drilling operations;

model borehole expected pressures for continued drilling; and

control said primary pump and fluid backpressure system in response to existing annular pressures and borehole expected pressures.

4. The system of claim 3, wherein said pressure monitoring system further includes communication means, processing means, and control means for controlling said primary pump and fluid backpressure system.

5. The system of claim 1, wherein said fluid backpressure system fluid source is said drilling fluid source.

6. The system of claim 1, wherein said fluid backpressure system fluid source is said fluid discharge outlet.

7. A method for controlling formation pressure during the drilling of a subterranean formation, the steps comprising:

deploying a drill string extending into a borehole, the drill string including a bottom hole assembly, the bottom hole assembly comprising, drill bit, sensors, and a telemetry system capable of receiving and transmitting data, including sensor data, said sensor data including at least pressure and temperature data;

providing a surface telemetry system for receiving data and transmitting commands to said bottom hole assembly;

selectively pumping a drilling fluid utilizing a primary pump from a drilling fluid source, through said drill string, out said drill bit and into an annular space created as said drill string penetrates the formation;

providing a fluid discharge conduit in fluid communication with said annular space for discharging said drilling fluid to a reservoir to clean said drilling fluid for reuse;

selectively increasing annular space drilling fluid pressure utilizing a fluid backpressure system connected to said fluid discharge conduit; said fluid backpressure system comprised of a flow meter, a fluid choke, a backpressure pump, and a fluid source.

8. The method of claim 7, further providing a pressure monitoring system for receiving drilling operational data, said drilling operational data including drill string weight on bit, drill string torque on bit, drilling fluid weight, drilling fluid volume, primary and backpressure pump pressures, drilling fluid flow rates, drill string rate of penetration, drill string rotation rate, and sensor data transmitted by said bottom hole assembly.

9. The method of claim 8, wherein said pressure monitoring system, utilizing said drilling operational data, further

monitors existing said annular space pressures during drilling operations;

models borehole expected pressures for continued drilling; and

controls said primary pump and fluid backpressure system in response to existing annular pressures and borehole expected pressures.

10. The method of claim 9, wherein said pressure monitoring system further includes communication means,, processing means, and control means for controlling said primary pump and fluid backpressure system.

11. The method of claim 7, wherein said fluid backpressure system fluid source is said drilling fluid source.

12. The method of claim 7, wherein said fluid backpressure system fluid source is said fluid discharge outlet.

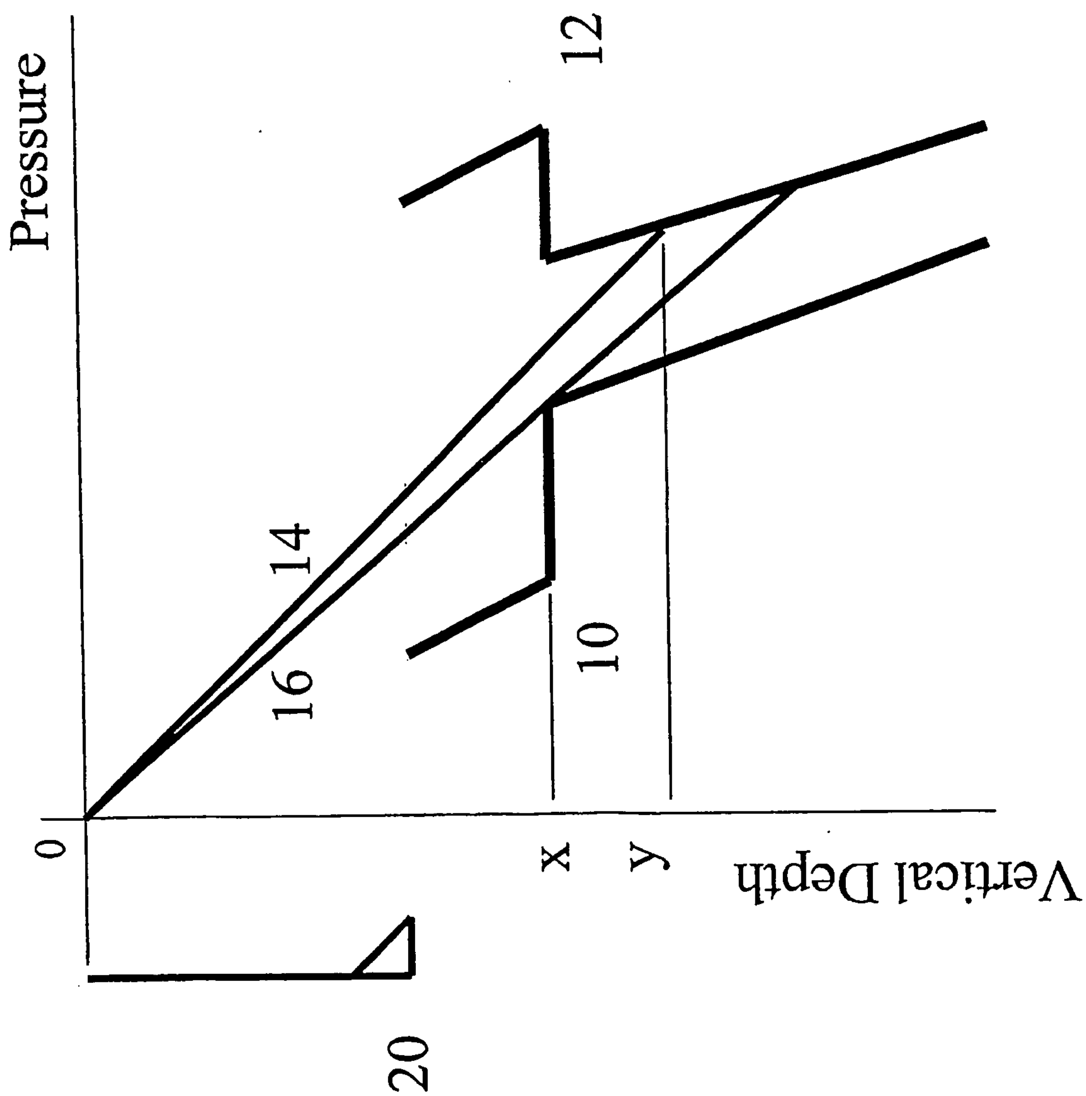


Fig 1

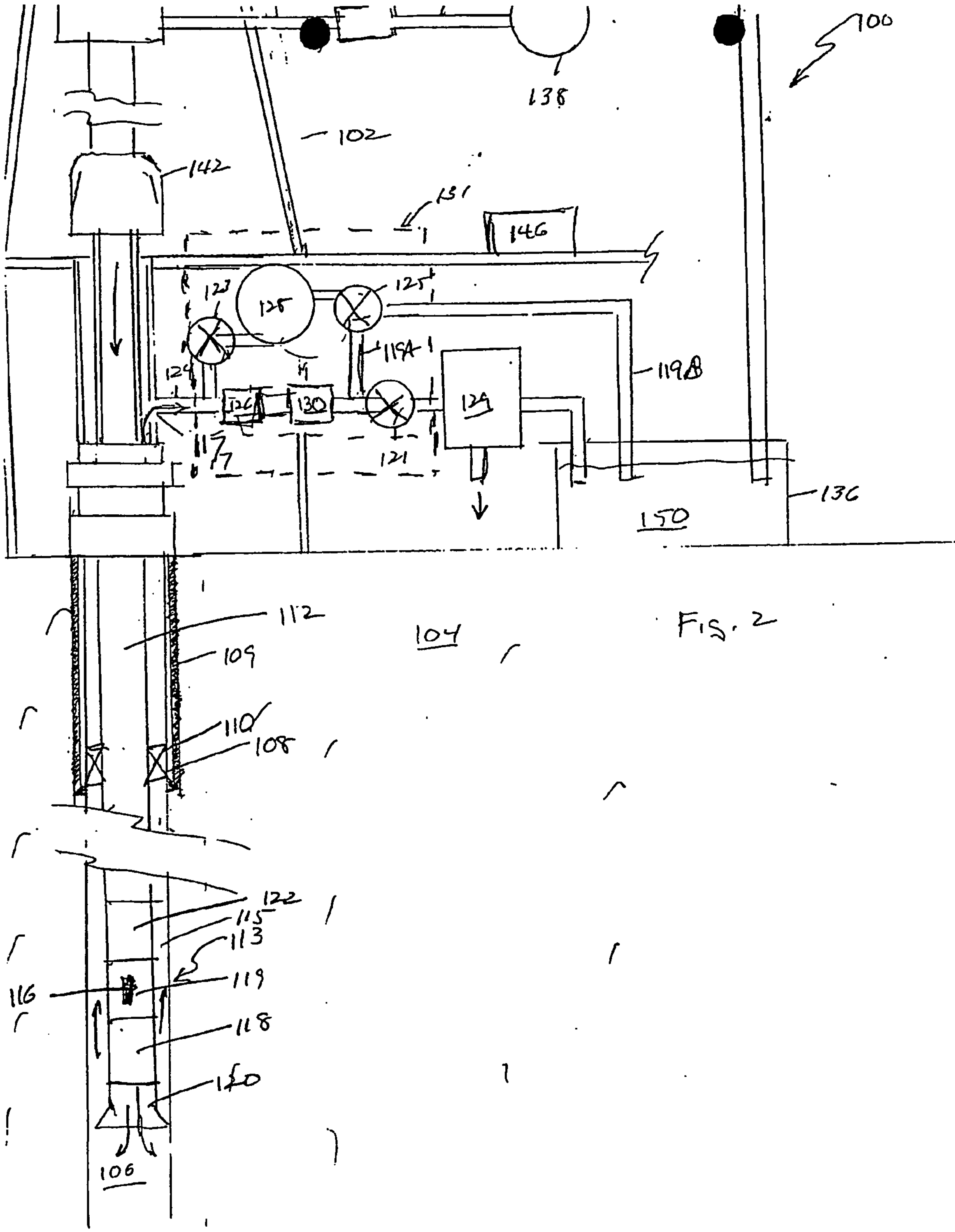

100
138
102
142
131
146
128
123
125
124
119A
119B
126
130
121
129
117
136
150
112
109
110
108
104
122
115
113
119
116
118
120
106

Fig. 2

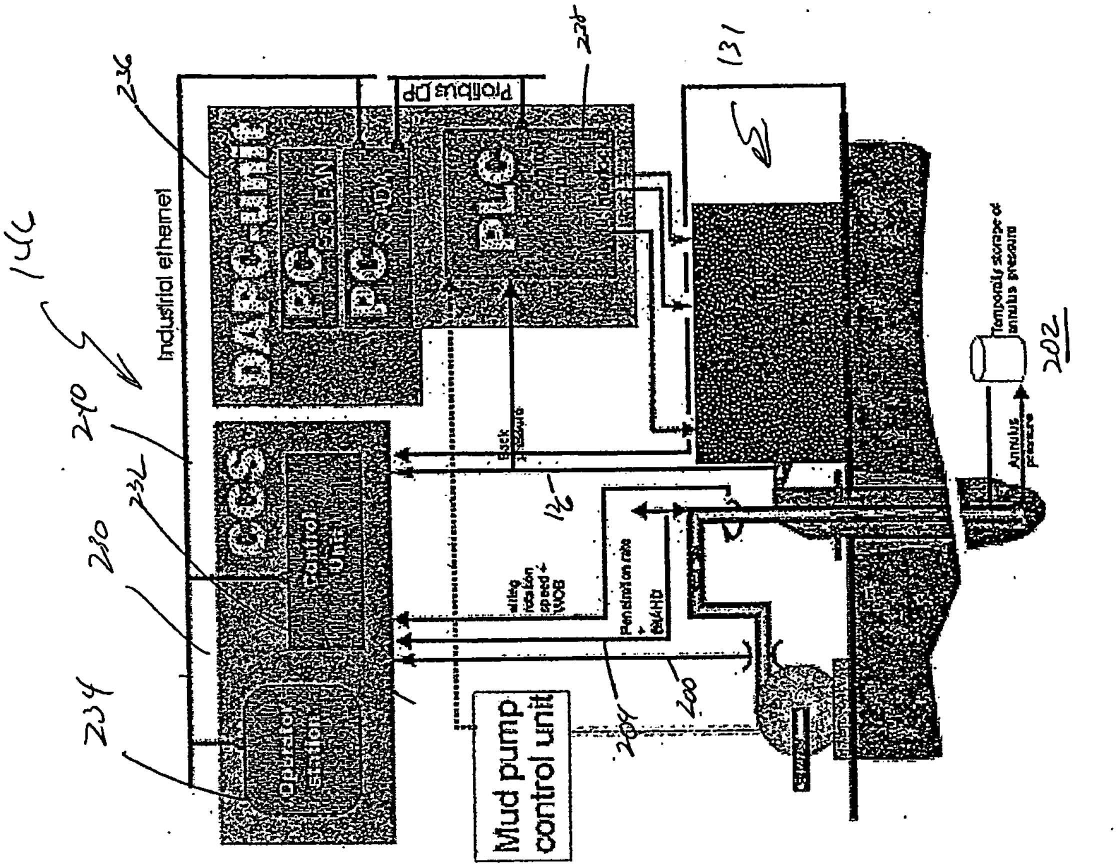
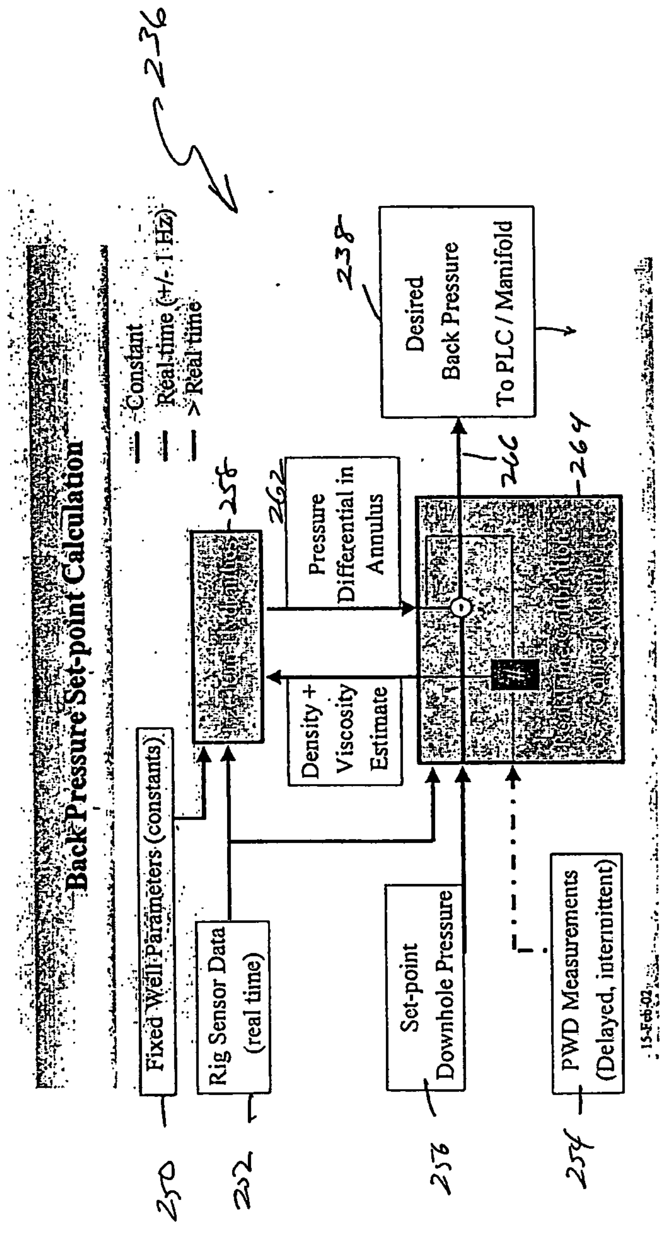

Industrial ethernet
Profibus DP
DAPC-unit
PC-CLEAN
PC
PLC
CCS
Control Unit
Operator Station
Mud pump control unit
Back pressure
string rotation speed + WOB
Penetration rate + BHP
Temporary storage of annulus pressure
Annulus pressure
140
240
230
232
234
236
238
131
12
204
200
202

Fig. 3



Back Pressure Set-point Calculation
Constant
Real-time (+/-.1 Hz)
> Real-time
236
Fixed Well Parameters (constants)
Rig Sensor Data (real time)
Set-point Downhole Pressure
PWD Measurements (Delayed, intermittent)
250
252
256
254
258
Density + Viscosity Estimate
262
Pressure Differential in Annulus
264
266
238
Desired Back Pressure
To PLC / Manifold
15-Feb-02

Fig. 4

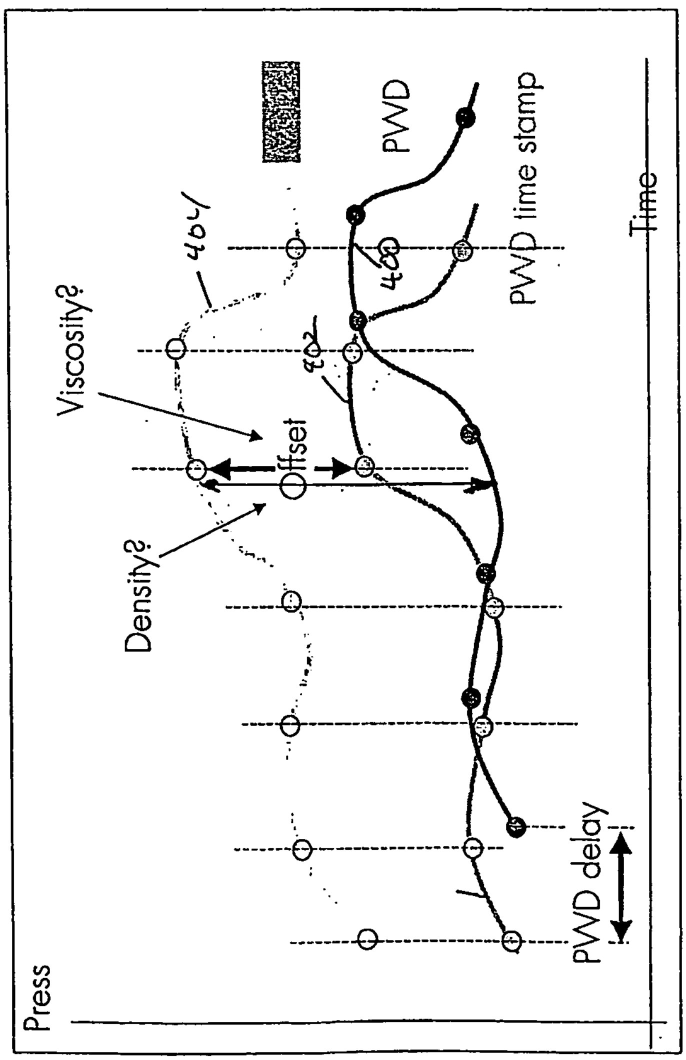

Press
Time
PWD
PWD time stamp
PWD delay
Density?
Viscosity?
Offset
404
400
402

FIG. 5

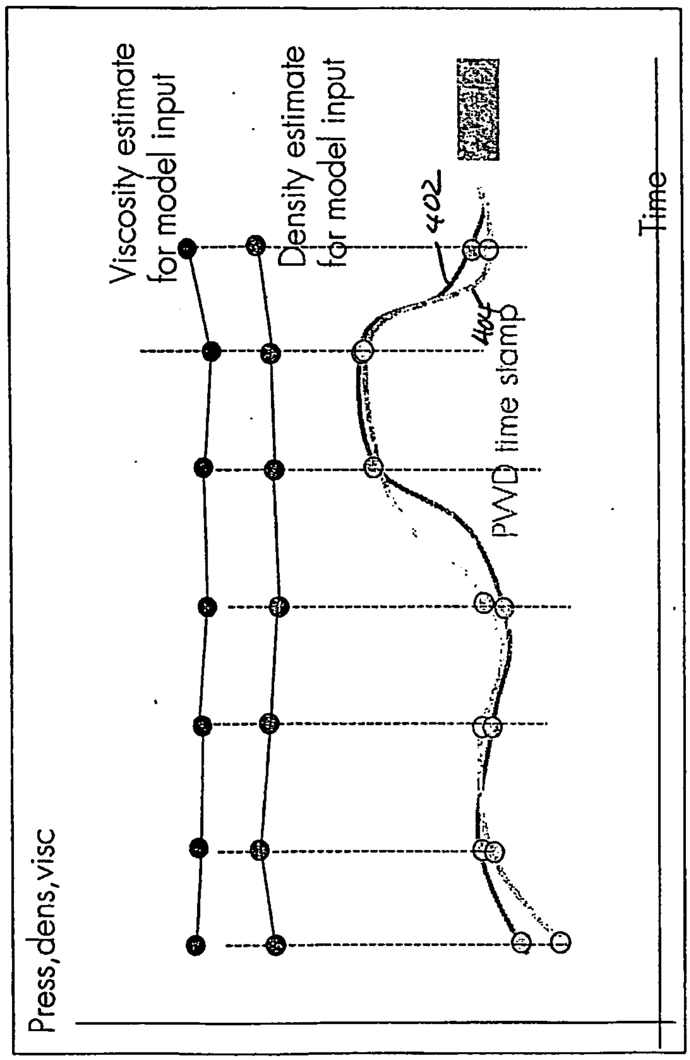

Press,dens,visc
Viscosity estimate
for model input
Density estimate
for model input
402
404
PWD time stamp
Time

Fig. 6

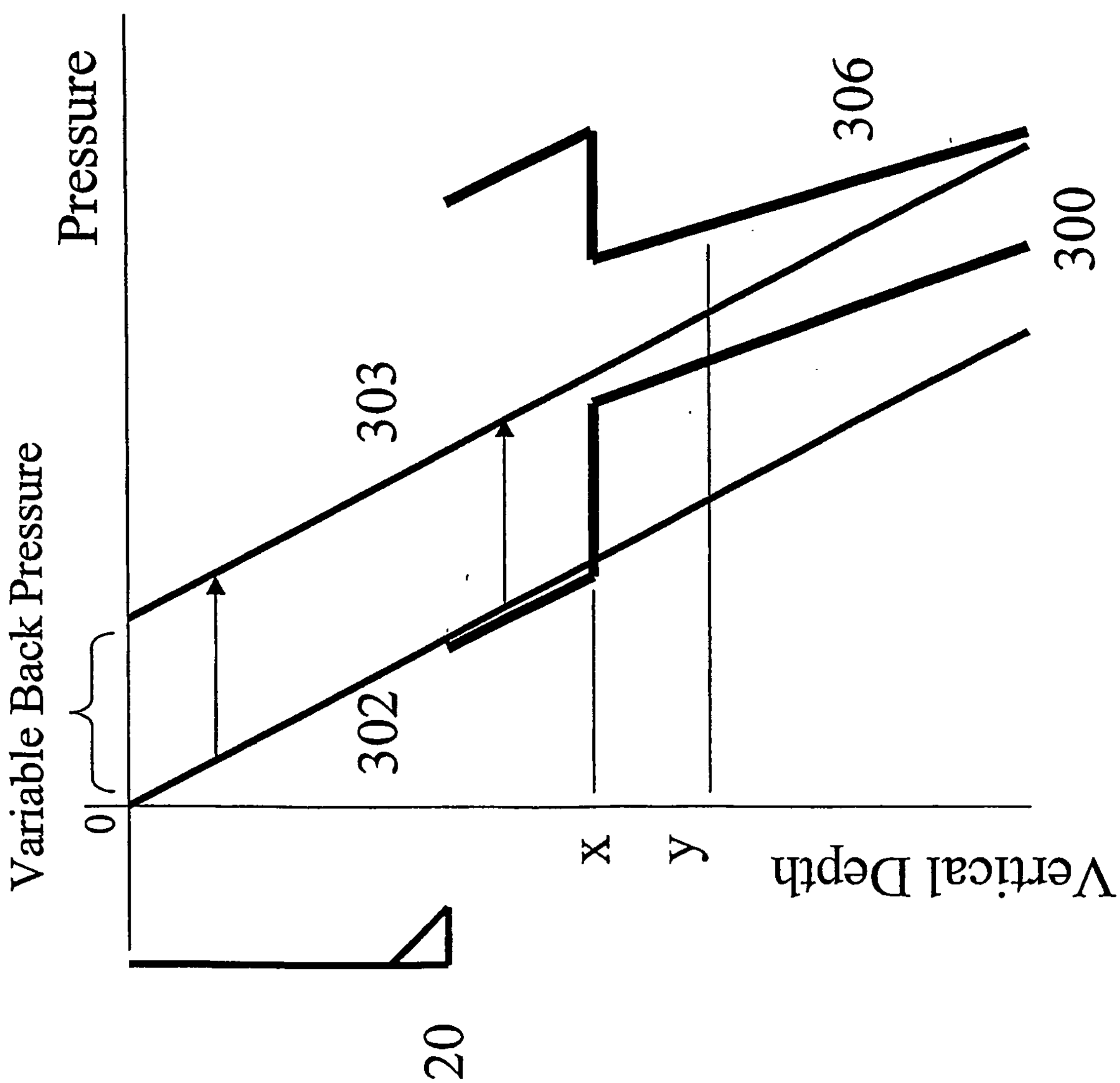

Variable Back Pressure
Pressure
0
302
303
306
300
x
y
Vertical Depth
20

Fig 7

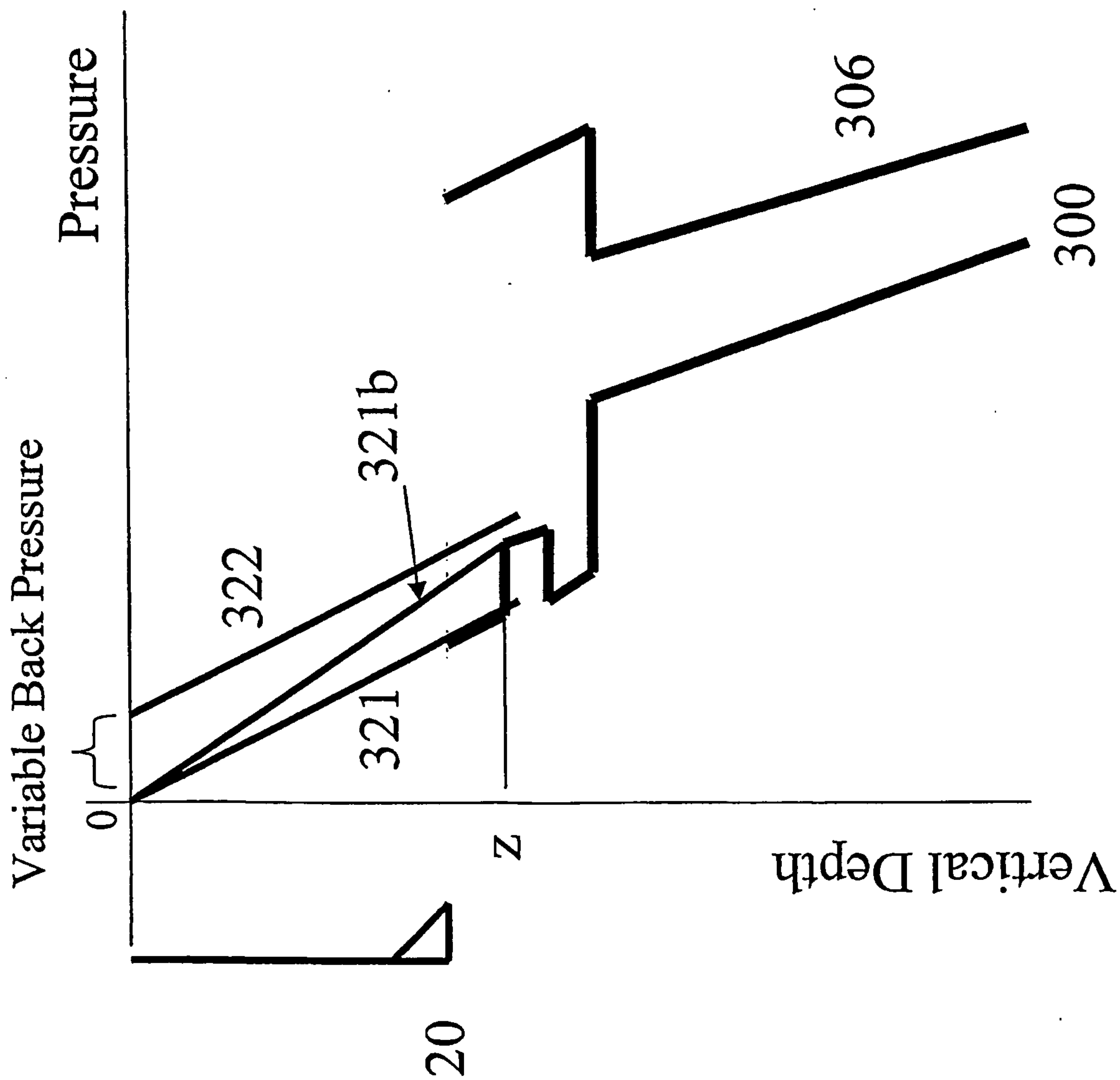

Variable Back Pressure
Pressure
0
322
321b
321
z
306
300
Vertical Depth
20

Fig 8

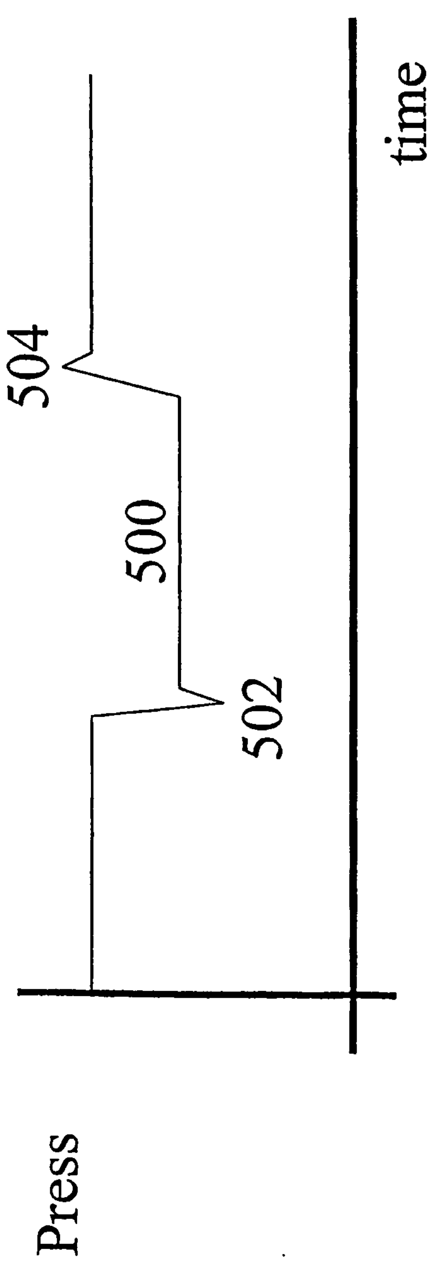


Fig 9A

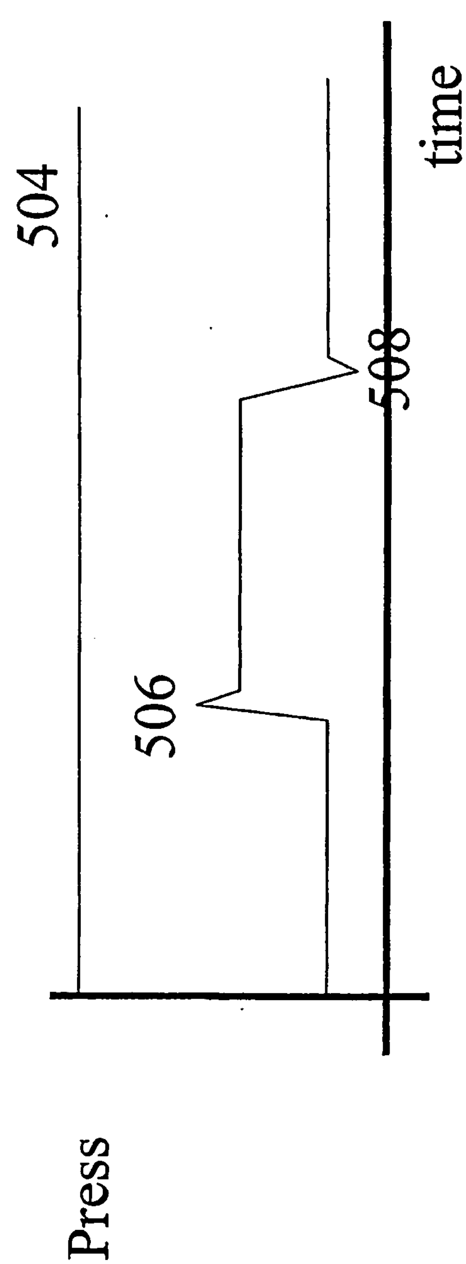


Fig 9B

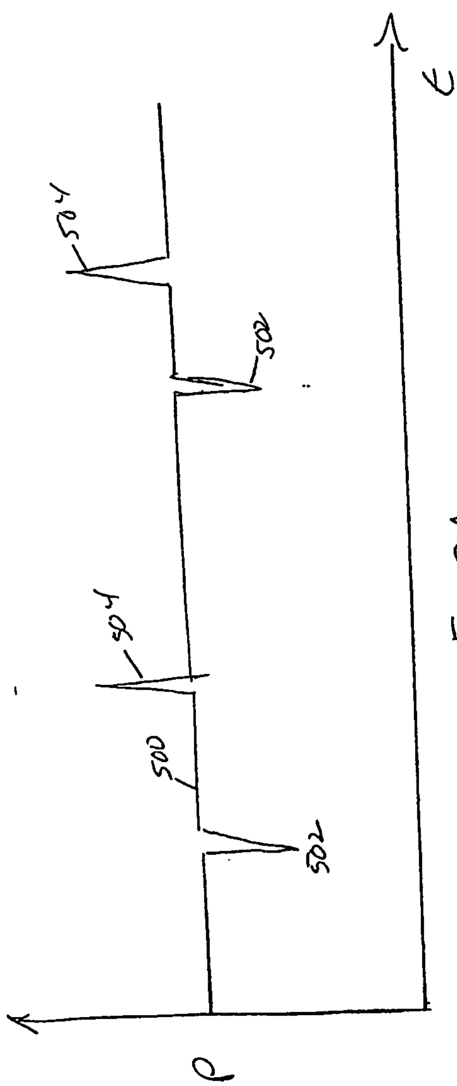


Fig. 9A

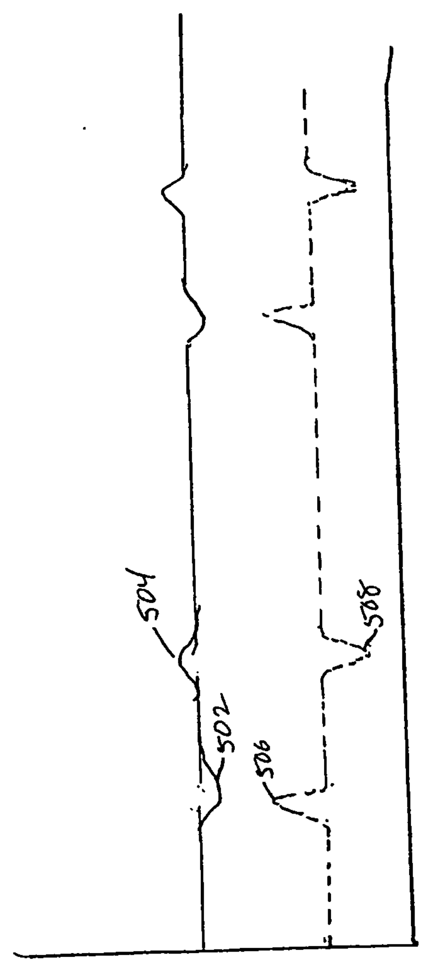


Fig. 9B

INTERNATIONAL SEARCH REPORT

International Application No
PCT/US 03/05012

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B21/08 E21B44/00

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	WO 00 79092 A (SHELL CANADA LTD ;SHELL INT RESEARCH (NL)) 28 December 2000 (2000-12-28) cited in the application abstract; figures page 4, line 30-35 page 5, line 19 - line 33 page 8, line 2 -page 9, line 16	1-12
Y	WO 00 04269 A (DEEP VISION LLC) 27 January 2000 (2000-01-27) abstract; figures page 5, line 22 -page 6, line 8 page 12, line 14 - line 20	1-12

-/--

[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

° Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier document but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
23 July 2003	30/07/2003

Name and mailing address of the ISA	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL – 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+31-70) 340-3016	Weiand, T

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	EP 0 436 242 A (SCHLUMBERGER SERVICES PETROL) 10 July 1991 (1991-07-10) abstract; figures page 3, line 49 -page 4, line 7 ---	1,7
A	US 4 709 900 A (DYHR EINAR) 1 December 1987 (1987-12-01) abstract; figures ---	1,7
P,X	US 2002/112888 A1 (LEUCHTENBERG CHRISTIAN) 22 August 2002 (2002-08-22) page 7, paragraph 103 - paragraph 105 ---	1,7
A	US 5 857 522 A (BRADFIELD DAVID H ET AL) 12 January 1999 (1999-01-12) cited in the application abstract; figures ---	1,7
A	US 6 035 952 A (BRADFIELD DAVID H ET AL) 14 March 2000 (2000-03-14) cited in the application abstract; figures ---	1,7
A	US 6 176 323 B1 (KRUEGER VOLKER ET AL) 23 January 2001 (2001-01-23) abstract; figures -----	1,7

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
PCT/US 03/05012

Patent document cited in search report	Publication date	Patent family member(s)		Publication date
WO 0079092 A	28-12-2000	AU	5816800 A	09-01-2001
		BR	0011830 A	19-03-2002
		CA	2373515 A1	28-12-2000
		CN	1357076 T	03-07-2002
		EG	22204 A	31-10-2002
		WO	0079092 A2	28-12-2000
		GB	2369638 A	05-06-2002
		NO	20016334 A	21-02-2002
		US	6352129 B1	05-03-2002
WO 0004269 A	27-01-2000	AU	4991099 A	07-02-2000
		AU	5001299 A	07-02-2000
		GB	2356657 A ,B	30-05-2001
		GB	2357102 A ,B	13-06-2001
		GB	2379947 A ,B	26-03-2003
		NO	20010198 A	06-03-2001
		NO	20010199 A	13-03-2001
		US	2002092655 A1	18-07-2002
		WO	0003600 A2	27-01-2000
		WO	0004269 A2	27-01-2000
		US	6415877 B1	09-07-2002
		US	6408948 B1	25-06-2002
EP 0436242 A	10-07-1991	GB	2239279 A	26-06-1991
		CA	2031357 A1	21-06-1991
		DE	69008329 D1	26-05-1994
		DE	69008329 T2	17-11-1994
		DK	436242 T3	29-08-1994
		EP	0436242 A1	10-07-1991
		NO	905384 A ,B,	21-06-1991
		US	5080182 A	14-01-1992
US 4709900 A	01-12-1987	DK	162885 A	12-10-1986
		AT	71442 T	15-01-1992
		DE	3683309 D1	20-02-1992
		DK	95886 A	12-10-1986
		EP	0199669 A2	29-10-1986
		JP	61290193 A	20-12-1986
		KR	9207709 B1	15-09-1992
		NO	860821 A ,B,	13-10-1986
US 2002112888 A1	22-08-2002	AU	1932202 A	01-07-2002
		WO	0250398 A1	27-06-2002
		US	2003079912 A1	01-05-2003
US 5857522 A	12-01-1999	AU	723022 B2	17-08-2000
		AU	2826897 A	26-11-1997
		CA	2252944 A1	13-11-1997
		DE	69704158 D1	05-04-2001
		DE	69704158 T2	02-08-2001
		EP	1048819 A1	02-11-2000
		EP	0897454 A1	24-02-1999
		NO	985098 A	30-12-1998
		WO	9742395 A1	13-11-1997
		US	6035952 A	14-03-2000
US 6035952 A	14-03-2000	US	5857522 A	12-01-1999
		AU	723022 B2	17-08-2000

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
PCT/US 03/05012

Patent document cited in search report		Publication date	Patent family member(s)			Publication date
US 6035952	A		AU	2826897	A	26-11-1997
			CA	2252944	A1	13-11-1997
			DE	69704158	D1	05-04-2001
			DE	69704158	T2	02-08-2001
			EP	1048819	A1	02-11-2000
			EP	0897454	A1	24-02-1999
			NO	985098	A	30-12-1998
			WO	9742395	A1	13-11-1997
US 6176323	B1	23-01-2001	AU	5248598	A	15-05-1998
			AU	8164898	A	19-01-1999
			GB	2334108	A ,B	11-08-1999
			WO	9900575	A2	07-01-1999

Form PCT/ISA/210 (patent family annex) (July 1992)